Petromet

RESOURCES LIMITED ANNUAL REPORT 1996

success through exploration

PROFILE PETROMET RESOURCES LIMITED IS AN ACTIVE NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION COMPANY. PETROMET'S OPERATIONS ARE FOCUSED IN WEST CENTRAL ALBERTA WHERE THE COMPANY HOLDS A LARGE UNDEVELOPED LAND BASE, EXTENSIVE INFRASTRUCTURE AND PROCESSING FACILITIES. PETROMET HAS GROWN ITS AVERAGE PRODUCTION FROM 5 MILLION CUBIC FEET OF NATURAL GAS EQUIVALENT PER DAY IN 1992 TO 42 MILLION CUBIC FEET EQUIVALENT PER DAY IN 1996 PRIMARILY THROUGH EXPLORATION.

PETROMET'S COMMON SHARES AND CONVERTIBLE DEBENTURES TRADE ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL PNT. THE COMMON SHARES ALSO TRADE ON NASDAQ (PNTGF).

PETROMET CHANGED ITS YEAR END FROM JANUARY 31 TO DECEMBER 31, EFFECTIVE DECEMBER 31, 1992. FOR PURPOSES OF THIS ANNUAL REPORT, THE GRAPH INFORMATION FOR 1992 REFLECTS ONLY 11 MONTHS OF OPERATION.

THE PHOTOGRAPHS IN OUR 1996 ANNUAL REPORT HIGHLIGHT OUR EXPLORATION AND DEVELOPMENT ACTIVITY ON COMPANY-OPERATED PROJECTS.

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbls	barrels
bcf	billion cubic feet
bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent (10 mcf = 1 bbl)
mbbls	thousand barrels
mcf	thousand cubic feet
mcfe	thousand cubic feet equivalent
mmbbls	million barrels
mmBOE	million barrels of oil equivalent
mmcf	million cubic feet
mmcfe	million cubic feet equivalent
NGL	natural gas liquids

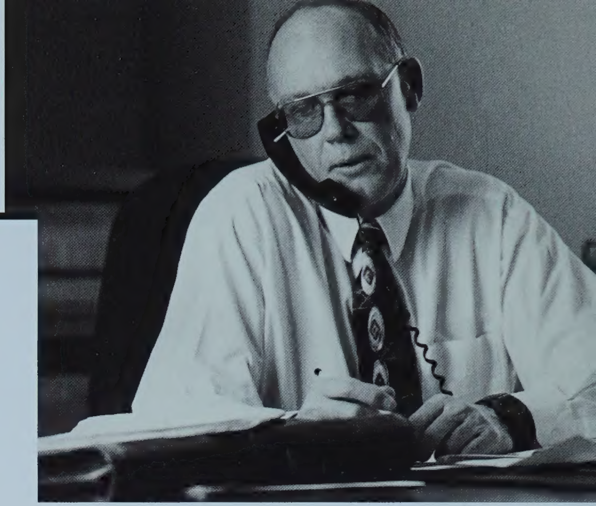
HIGHLIGHTS

Financial ($ millions except per share data)	1996	1995	% CHANGE
Gross revenue	27.9	19.1	46
Net income	5.9	1.7	247
Per share	0.17	0.05	240
Cash flow	15.9	9.1	74
Per share	0.46	0.29	59
Capital expenditures	23.2	37.9	-39
Long term debt	38.5	45.6	-16
Shareholders' equity	82.4	66.6	24
Average shares outstanding	34,347,166	31,611,591	9
Operating			
Production			
Natural gas (mmcf/d)	33.1	27.0	23
Oil & NGL (bbls/d)	859	801	7
Reserves			
Natural gas (bcf)			
Proven	157.4	138.3	14
Proven plus probable	207.2	171.1	21
Oil & NGL (mbbls)			
Proven	3,649	3,721	-2
Proven plus probable	4,559	4,656	-2
Undeveloped land (thousands of acres)			
Gross	457	299	53
Net	414	256	62
Average working interest (%)	90.6%	85.7%	6
Drilling activity			
Gross	29	24	21
Net	21	18	17
Employees			
Head office	19	19	–
Field	10	7	43

NOTICE OF ANNUAL GENERAL MEETING The Annual General Meeting of shareholders will be held on May 21, 1997 at 3:00 pm at the Westin Hotel, 320 – 4 Ave. S.W., Calgary, Alberta. All shareholders and other interested parties are invited to attend.

LETTER

TO SHAREHOLDERS

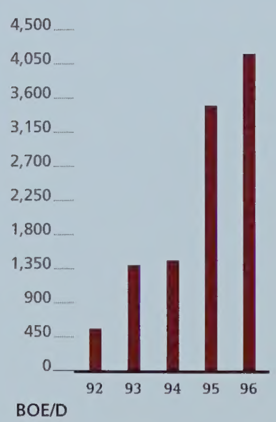


Laurie J. Smith, President & Chief Executive Officer

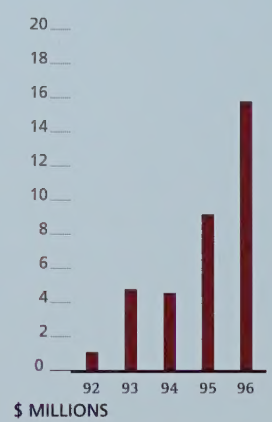
FOR PETROMET, 1996 WAS A YEAR OF SIGNIFICANT PROGRESS AND GROWTH. IN COMPARING OUR FINANCIAL AND OPERATING RESULTS WITH THOSE OF ONE YEAR AGO, IT IS EVIDENT THAT THE CONSISTENT IMPLEMENTATION OF OUR CORPORATE STRATEGIES HAS BEEN THE CORNERSTONE OF OUR SUCCESS.

- Daily production increased 19 percent to 4,169 barrels of oil equivalent in 1996
- Cash flow increased 74 percent to $15.9 million
- Net income more than tripled to $5.9 million
- Petromet's undeveloped land acreage grew to 414,000 net acres in 1996 compared to 256,000 net acres in 1995

PRODUCTION



CASH FLOW



OUR RESULTS Financially, Petromet achieved record results. Cash flow from operations increased 74 percent to $15.9 million in 1996 compared to $9.1 million in 1995. Net income rose 247 percent to $5.9 million in 1996 from $1.7 million in 1995. On a per share basis, cash flow was $0.46 and net income was $0.17 in 1996 compared to $0.29 and $0.05, respectively, in 1995. In addition, we reduced our total debt in 1996 to $38.5 million, representing 2.4 times cash flow for 1996. Looking forward into 1997, we anticipate this ratio will be less than two times cash flow. Petromet's continued emphasis on efficiency, ownership of facilities and strict cost controls, both at the head office and in the field, resulted in general and administrative costs of $0.90 per barrel of oil equivalent and operating costs of $2.09 per barrel of oil equivalent. Capital expenditures during 1996 totalled $23.2 million of which $17.5 million was directed towards exploration and development activity and the remainder to land and facilities.

Operationally, we are pleased to report that our daily production increased 19 percent in 1996 to 4,169 barrels of oil equivalent from 3,501 barrels of oil equivalent in 1995. These production increases were achieved through our exploration and development success at Bigstone, Pass Creek and Wild River. Petromet's extensive land position remains focused in our core areas in west central Alberta. Our aggressive land strategy resulted in substantial increases in undeveloped land acreage to 414,000 net acres in 1996 from 256,000 net acres in 1995. Petromet also achieved growth in its reserve base in 1996. Natural gas reserves increased 21 percent to 207.2 billion cubic feet from 171.1 billion cubic feet in 1995. Oil and natural gas liquids reserves decreased slightly to 4.6 million barrels in 1996 from 4.7 million barrels in 1995. At year-end, our reserve life index was approximately 13 years based on 1996 production and proven reserves.

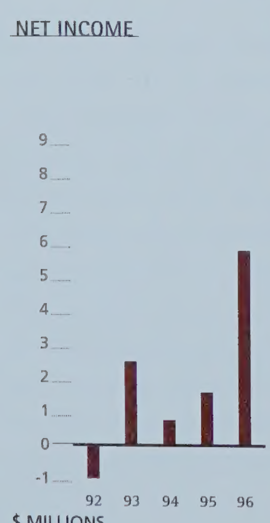
SUCCESS THROUGH EXPLORATION Petromet's growth has been achieved primarily through exploration. We internally generate our own prospects and we're focused on natural gas. In fact, if we take a closer look at the history of our Bigstone area, it provides us with a good example of our corporate strategies in action.

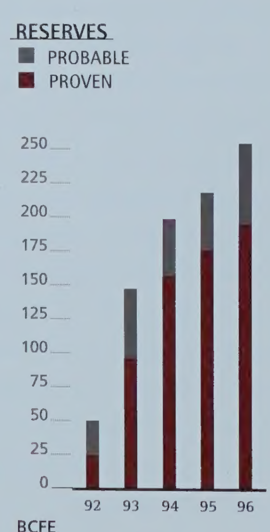
In March 1993, we drilled our first well in the Bigstone area. Four years later, Bigstone is a major production centre currently encompassing 35 producing wells. Activity during the past four years has included building on our extensive infrastructure of roads and gathering systems, and the construction of compression and plant facilities. Our continued growth in this area includes the expansion during 1997 of the Bigstone West Gas Plant from 65 million cubic feet per day to 85 million cubic feet per day and ongoing exploration on our extensive land holdings within this 400 square mile area.

While Bigstone is Petromet's flagship area, this approach has also proven successful in our Wild River area. Our other core area of West Central Foothills will be pursued in much the same manner. In each of these areas, Petromet has a large focused land position where we are actively exploring and developing our asset base. Similar to our approach at Bigstone, we are investing significant capital in acquiring large land holdings, and identifying drilling locations through geology and seismic. We will continue to benefit from economies of scale which will flow to our bottom-line results as we carry out our aggressive exploration and development program in 1997 and beyond.

FINANCING ACTIVITIES In November 1996, Petromet completed the issuance of 3.1 million flow-through common shares at an issue price of $3.30 per share for gross proceeds of $10.2 million. Proceeds from this financing are being used to fund our ongoing exploration activities.

OUTLOOK Looking forward into 1997, we are excited about our prospects for continued growth. Our initial capital expenditure budget is approximately $30 million which will be largely financed by cash flow. More than half of this budget is directed towards exploration and development activity. Exploration successes will determine future budget expansions. We will continue to focus exploration and development efforts in our core areas within our extensive land holdings. We expect that land sale activity levels will remain high in 1997, similar to the activity that occurred in the last half of 1996. In this environment, our objective is to continue to expand our land position in core areas.





We expect that the oil and gas industry will continue to operate at a fast pace in 1997 and we are confident that we can compete in this environment. Depressed gas storage levels, cold weather conditions across North America and indications that the deliverability surplus in western Canada is lower than expected have all had a positive impact on gas prices in early 1997. Also, as a result of our strategy to own and operate our production facilities, we will continue to see low operating costs; therefore, any rise in natural gas prices will contribute to our bottom-line.

Petromet has never wavered from its corporate strategies and the individuals within our company pursue these strategies with commitment and dedication. Our expertise lies in the area of natural gas, and we continue to focus on what we do best, in an area of Alberta that we know best. Our growth over the past year is a direct result of the combined effort of each discipline within our Company – from land, engineering and operations to marketing and finance. The expertise of our people is evident in our results, and I thank our employees, both in the field and in the head office, for their diligence and hard work. I also want to thank you, our shareholders, for your continued support in 1996 and also our directors for their advice and guidance. A farewell and thank you to John C. Lamacraft, who has served on our Board since May 1994 and resigned in October 1996. In his place, we welcome Charles J. Howard. Mr. Howard has a long successful history in the investment business. He is President of Ausnoram Holdings Limited.

Laurie J. Smith
President and Chief Executive Officer
April 1, 1997

PETROMET HAS ACHIEVED CONTINUED GROWTH THROUGH THE CONSISTENT IMPLEMENTATION OF ITS CORPORATE STRATEGIES. OVER THE PAST SEVERAL YEARS, PETROMET HAS FOCUSED ON DRILLING AND BUILDING THE NECESSARY INFRASTRUCTURE OF GATHERING SYSTEMS, COMPRESSION AND PLANT FACILITIES TO BRING RESERVES ONSTREAM QUICKLY AND EFFICIENTLY. THE COMPANY HAS BUILT A SUBSTANTIAL LAND PORTFOLIO FOR FUTURE EXPLORATION AND DRILLING. PETROMET IS WELL-POSITIONED TO ACHIEVE SIGNIFICANT CASH FLOW, EARNINGS, PRODUCTION AND RESERVE GROWTH IN 1997 AND BEYOND THROUGH AGGRESSIVE EXPLORATION AND DEVELOPMENT IN OUR EXISTING AND NEW CORE AREAS. THE STRATEGIES THAT HAVE DIRECTED OUR EFFORTS IN THE PAST AND WHICH WILL CONTINUE TO GUIDE US IN THE FUTURE INCLUDE:

- Focus on multizone potential of natural gas prone areas in west central Alberta;
- Exploration and development within undeveloped land holdings base;
- Concentrate on reservoirs with long-life reserves and higher production rates;
- Maintain high interests, operate and own production facilities;
- Purchase additional interests in core areas;
- Use quality 2-D and 3-D seismic to reduce exploration risk; and
- Use new technology in drilling and completion operations to reduce cost and enhance well productivity.

1997 OBJECTIVES

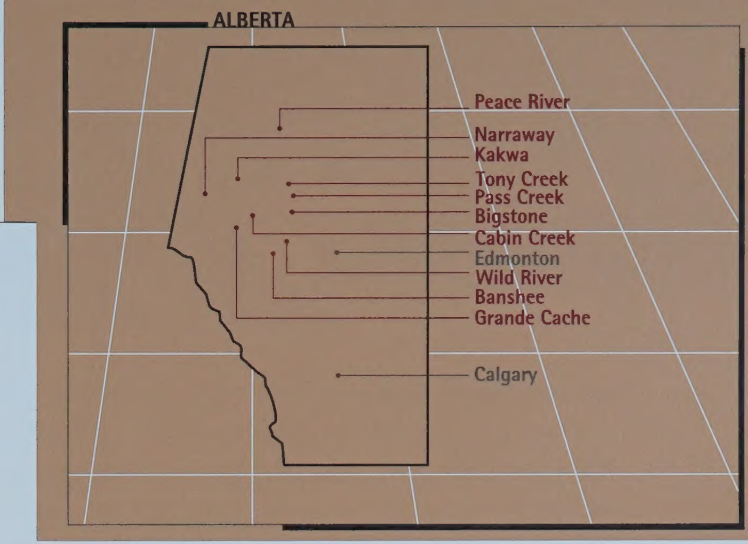
- Aggressive exploration and development in Petromet's core areas of Bigstone, Wild River and West Central Foothills.
- Drill a minimum 30 wells.
- Expand our 54 percent owned gas plant at Bigstone from 65 million cubic feet per day to 85 million cubic feet per day capacity.
- Achieve minimum production growth of 20 to 25 percent.
- Minimum reserve growth of two times annual production at finding costs of $6.50 or less per barrel of oil equivalent.
- Continue to maintain low operating and general and administrative costs.

OPERATIONS REVIEW

thinking long term

OPERATIONS

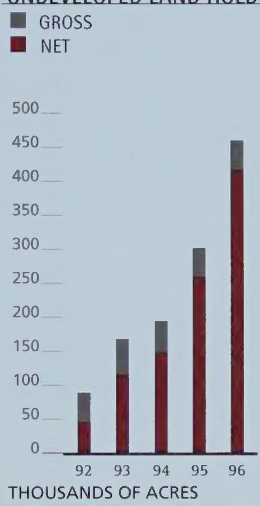
REVIEW



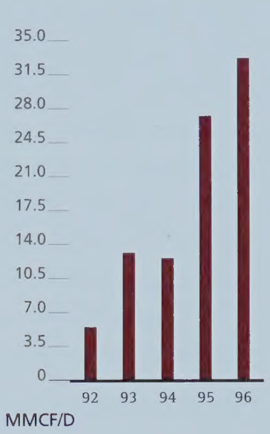
LAND In 1996, Petromet continued to pursue its aggressive land acquisition strategy and, as a result, the Company expanded its undeveloped land base to 414,371 net acres from 256,183 net acres in 1995. This 62 percent increase in net acreage was achieved through active participation at Crown land sales, farm-in arrangements, acquisitions from other industry participants and land swaps within Petromet's core areas of operation. Petromet's average working interest in this land base is 90 percent.

During 1996, land purchases totaled $3.0 million compared to $1.9 million in 1995. Petromet plans to maintain a high level of activity at Crown sales in 1997 supplemented by increased property swaps and farmins in order to support its ongoing exploration and development program.

UNDEVELOPED LAND HOLDINGS



NATURAL GAS PRODUCTION



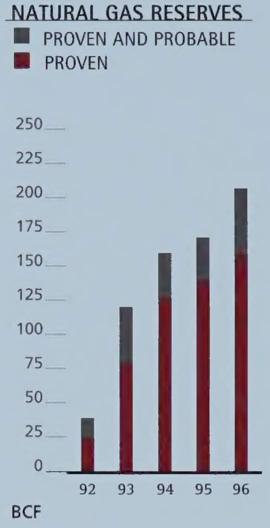
DRILLING Petromet participated in the drilling of 29 gross wells (21 net) in 1996 compared to 24 gross wells (18 net) in 1995. This program resulted in 17 gas wells, three oil wells and nine dry holes, representing a 69 percent success rate. Consistent with Petromet's goal of pursuing high working interests and operatorship, 86 percent of these wells were Company-operated. Petromet will direct a similar percentage of its capital budget towards exploration and development activity and the Company plans to drill approximately 30 wells in 1997.

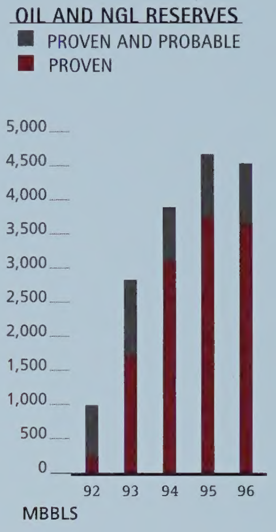
LAND HOLDINGS (at December 31) (acres)	1996		1995	
	Gross	Net	Gross	Net
Undeveloped	457,483	414,371	299,042	256,183
Developed	62,257	36,781	62,875	33,917
Total	519,740	451,152	361,917	290,100

RESERVES At December 31, 1996, Petromet's natural gas reserves increased to 207.2 billion cubic feet from 171.1 billion cubic feet in 1995. The liquids reserves were reduced slightly to 4.6 million barrels in 1996 from 4.7 million barrels in 1995 due to the liquids content of the gas from recent discoveries being leaner, dispositions and revisions of prior estimates.

During 1996, exploration and development added proven reserves of 34.7 billion cubic feet of gas and 0.83 million barrels of oil and natural gas liquids (43.0 bcfe). Growth in reserves is attributable to new reserve discoveries in the Bigstone area (which includes Pass Creek and Tony Creek), Peace River and Wild River.

On a barrel of oil equivalent basis, increases in Petromet's proven and probable reserves replaced production by a factor of 3.3 in 1996. The reserve life index is 12.7 years based on 1996 production and proven reserves at year end.





DRILLING ACTIVITY	1996		1995	
	Gross	Net	Gross	Net
Natural gas	17	11	17	13
Oil	3	2	2	2
Dry	9	8	5	3
Total	29	21	24	18
Success rate	69%		79%	
Average working interest	73%		74%	

RESERVES SUMMARY	Natural Gas (bcf)		Oil & NGL (mbbls)	
(at December 31)	1996	1995	1996	1995
Proven	157.4	138.3	3,649	3,721
Probable	49.8	32.8	910	935
Total	207.2	171.1	4,559	4,656

RESERVE RECONCILIATION	Natural Gas (bcf)			Oil & NGL (mbbls)		
	Proven	Probable	Total	Proven	Probable	Total
Balance, December 31, 1995	138.3	32.8	171.1	3,721	935	4,656
Acquisitions	7.0	0.9	7.9	127	35	162
Discoveries and revisions	34.7	18.0	52.7	826	181	1,007
Revisions of prior estimates	(3.0)	(1.9)	(4.9)	(486)	(241)	(727)
Dispositions	(7.5)	–	(7.5)	(225)	–	(225)
Production	(12.1)	–	(12.1)	(314)	–	(314)
Balance, December 31, 1996	157.4	49.8	207.2	3,649	910	4,559

PRODUCTION During 1996, Petromet's average natural gas production rose 23 percent to 33.1 million cubic feet per day from 27.0 million cubic feet per day in 1995. Average crude oil and natural gas liquids production increased marginally to 859 barrels per day in 1996 from 801 barrels of per day in 1995. This marginal increase is due to new discoveries of leaner natural gas and also reflects the sale of production from several minor properties. On a million cubic feet equivalent basis, production averaged 41.7 in 1996 compared to 35.0 in 1995. These production gains were the result of expansion activity in the Pass Creek area, development activity at Wild River and the continued impact of Petromet's successful operations in the Bigstone area.

FINDING AND DEVELOPMENT COSTS Finding and development costs, for proven and half probable reserves, were significantly reduced in 1996 to $5.52 per BOE from $11.78 per BOE in 1995. Over the five year period 1992 to 1996, Petromet's finding and development costs for proven and half probable reserves averaged $5.72 per BOE. One of Petromet's corporate business strategies is to own facilities. During 1994 and 1995, finding and development costs included $32 million in facilities.

SUMMARY OF 1996 PRODUCTION AND YEAR END RESERVES

	Production			Proven Reserves		
	Natural Gas mmcf/d	Oil & NGL bbls/d	Total mmcfe/d	Natural Gas bcf	Oil & NGL mbbls	Total bcfe
Bigstone	26.3	796	34.3	101.8	3,057.7	132.4
Wild River	5.2	25	5.4	41.7	332.5	45.0
Other	1.6	38	2.0	13.9	258.7	16.5
Total	33.1	859	41.7	157.4	3,648.9	193.9

ANNUAL FINDING AND DEVELOPMENT COSTS

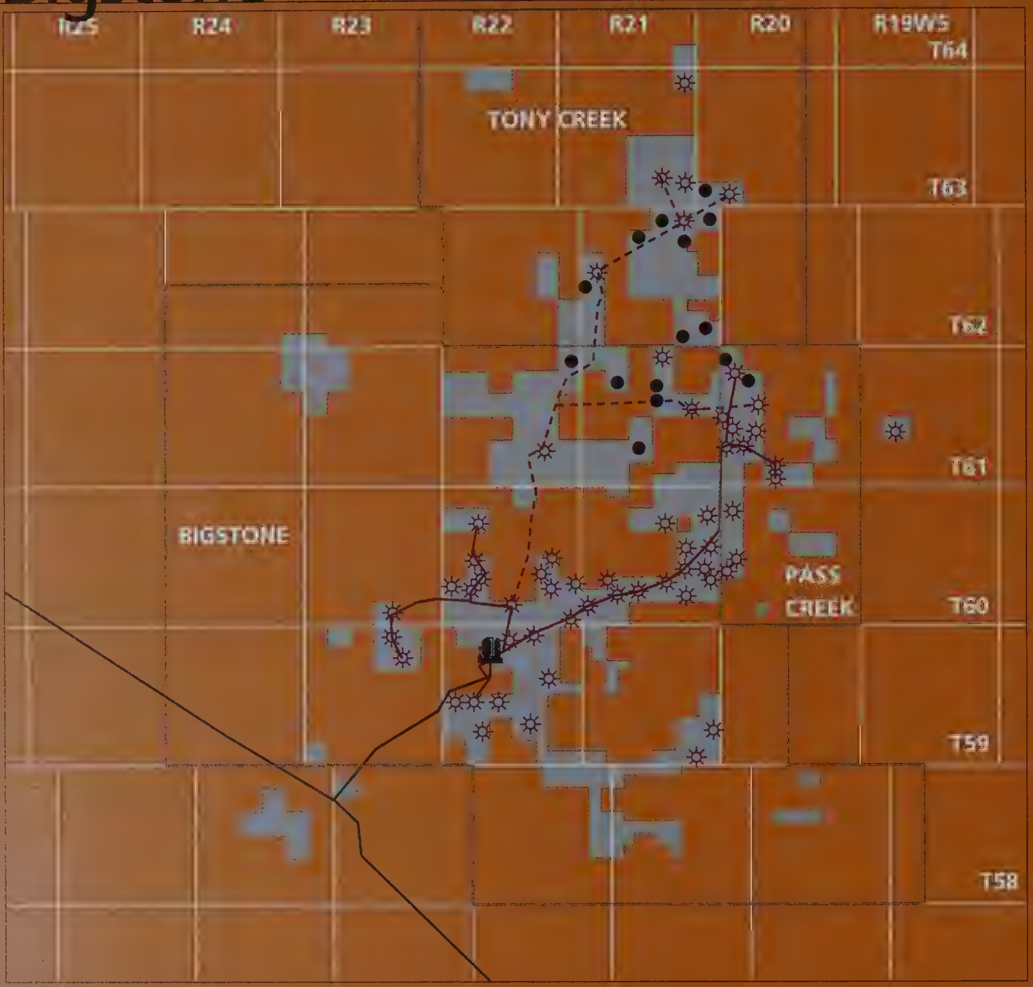
	1996	1995	1994
Capital expenditures ($ millions)			
Exploration and development	$ 17.5	$ 18.5	$ 30.2
Facilities	3.1	13.1	18.7
Land	3.4	2.1	6.3
Acquisitions, net of dispositions	(0.8)	4.2	1.9
Total capital expenditures	$ 23.2	$ 37.9	$ 57.1
Proven reserves added (mmboe)	3.4	3.2	6.7
Average cost per BOE (proven)	$ 6.90	$ 11.84	$ 8.52
Proven and 50% probable reserves added (mmboe)	4.2	3.2	6.1
Average cost per BOE (proven & 50% probable)	$ 5.52	$ 11.78	$ 9.29

CUMULATIVE FINDING AND DEVELOPMENT COSTS

	1994 – 96	1992 – 96
Total capital expenditures ($ millions)	$ 118.2	$ 144.2
Proven reserves added (mmboe)	13.3	22.4
Average cost per BOE (proven)	$ 8.91	$ 6.45
Proven and 50% probable reserves added (mmboe)	13.6	25.2
Average cost per BOE (proven & 50% probable)	$ 8.72	$ 5.72

Above left: Kim Nordquist, Bert Gracey and Scott Gordon Above right: Doug Andrews, Dave Erickson, Jeremy Newton and Keith Mychaluk

Bigstone



Bigstone continues to be Petromet's largest producing asset, which encompasses Pass Creek and Tony Creek. As a result of Petromet's substantial capital investment in this area over the past two years, the Company has realized significant economies of scale. During 1997, Petromet plans to expand the capacity of its 54 percent owned gas plant at Bigstone West. The Company is pursuing an aggressive exploration and development program in the area with the drilling of approximately 15 wells.

PROPERTY DESCRIPTION

- Multi-zone potential, with liquids rich gas
- Producing zones include the Dunvegan, Gething, Viking, Notikewan, Cadomin and Triassic formations
- 35 producing gas wells in the area
- Low operating costs
- Operate a 54% owned modern gas processing facility designed to process 65 mmcf/d of natural gas and 2,600 bbls of natural gas liquids

UNDEVELOPED LAND HOLDINGS

- 82,240 gross acres
- 70,954 net acres

1996 ACTIVITY

- Bigstone: drilled 11 gas wells (seven net)
- Pass Creek: shot two high resolution seismic programs
- Tony Creek: shot one seismic program, completed a successful farm-in on four sections of land, drilled one successful gas well

AVERAGE NET PRODUCTION

- 26.3 mmcf/d of natural gas
- 796 bbls/d of natural gas liquids

1997 ACTIVITY

- Expand capacity at the Bigstone West Gas Plant from 65 mmcf/d to 85 mmcf/d
- Pass Creek: drill six wells, shoot additional seismic, build a pipeline crossover to Tony Creek to increase gas production from the area
- Tony Creek: construct a gas gathering pipeline (operational by July 1, 1997) from Tony Creek to the Bigstone gas plant; tie-in four existing wells and drill six wells in 1997; shoot an additional high resolution seismic program to delineate drilling targets; evaluate developing oil potential on Company lands
- Continue to increase and consolidate land position within this area via swaps, farm-ins and acquisitions

LEGEND	● PETROMET LOCATION
☼ PETROMET GAS WELLS	■ PETROMET LANDS

Wild River

As at Bigstone, Petromet is benefiting from the infrastructure that the Company has established in the Wild River area. Petromet owns a modern facility with processing capacity of 25 million cubic feet per day as well as an extensive gas gathering system. During 1996, the Company recorded production gains through the recompletion and tie-in of re-entered wells. In 1997, Petromet will continue its recompletion program at Wild River. The Company also plans to shoot additional 3-D seismic in order to identify further drilling locations which may include drilling for additional Leduc Pinnacle reefs.

PROPERTY DESCRIPTION

- Characterized by low deliverability gas production from long life reserves in low permeability gas reservoirs
- Produces sweet dry gas from two Leduc reef wells
- Produces gas with natural gas liquids from Viking, Falher, Bluesky and Cadomin formations
- Operate a 65% owned gas processing facility designed to process 10 mmcf/d of liquids rich gas and 15 mmcf/d of dry gas
- Nine producing gas wells

UNDEVELOPED LAND HOLDINGS

- 35,200 gross acres
- 28,242 net acres

1996 DRILLING AND RE-ENTRY ACTIVITY

- Three gas wells (2.5 net wells)

AVERAGE NET PRODUCTION

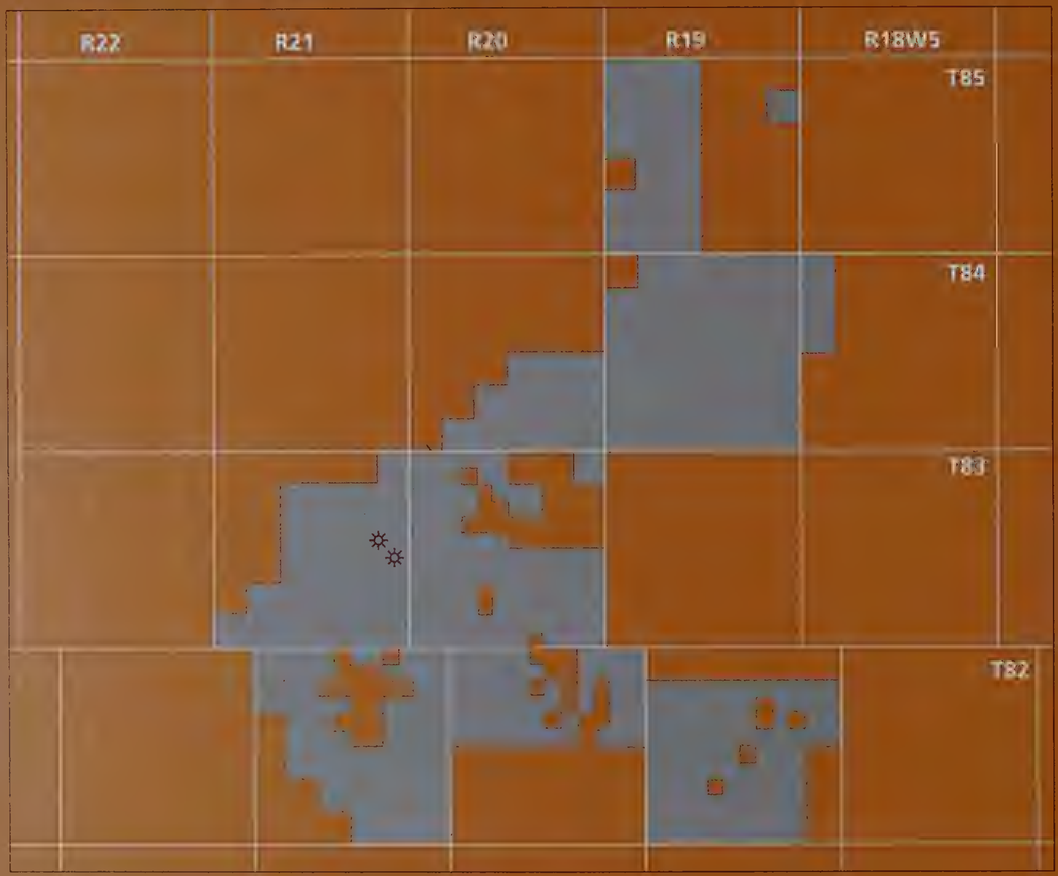
- 5.2 mmcf/d of natural gas
- 25 bbls/d of natural gas liquids

1997 ACTIVITY

- Shoot a 3-D seismic program and tie-in of Petromet and third party gas to increase plant throughput and processing efficiency
- Continue recompletion program to comingle production
- Consolidate and increase land holdings

GATHERING SYSTEM	NOVA PIPELINE
GATHERING SYSTEM 1997	PETROMET GAS PLANT

Peace River Area



During 1996, Petromet significantly expanded its land position in the Peace River area. The Company acquired 92,300 net acres of undeveloped land, and owns a 100 percent working interest in these lands.

PROPERTY DESCRIPTION

- Petromet holds an extensive 100 percent interest acreage position
- Two shut-in gas wells

UNDEVELOPED LAND HOLDINGS

- 110,700 acres

1996 ACTIVITY

- Purchased a Bluesky gas well and delineated a Bluesky gas pool through drilling
- Shot a 2-D seismic program
- Purchased a large block of 100 percent working interest exploration lands

1997 ACTIVITY

- Shoot additional 2-D seismic programs
- Further drilling will commence in late 1997 following the evaluation of additional seismic programs
- Construct necessary infrastructure to produce the Bluesky gas pool

LEGEND		
		PETROMET LANDS
	☼	PETROMET GAS WELLS

West Central Foothills Area

The Company has expanded its land position in the West Central Foothills to 87,880 net acres of undeveloped land. The West Central Foothills is a relatively new project area consisting of large acreage positions at Banshee, Cabin Creek, Grand Cache and Narraway. At Kakwa, Petromet has farmed into a large acreage position. Petromet holds a 100 percent working interest in all of the plays in this area. Petromet is anticipating an active drilling program over the next several years to fully explore and develop the Company's significant land base. During 1997, the Company plans to shoot seismic and drill several wells.

BANSHEE

- Prospective for Cardium gas
- 1997 plans include a 2-D seismic program and potential drilling pending results of seismic evaluation
- Drilling locations on faulted structures identified through seismic
- 14,920 acres

CABIN CREEK

- Deep Basin gas potential
- Prospective for Cardium, Dunvegan, Gething and Cadomin gas
- Purchase additional seismic; shoot 2-D seismic; development dependent on seismic results, drill two wells in late 1997/1998
- 34,560 acres

GRANDE CACHE

- Large acreage position on fault structure
- Large reserve potential for gas
- Prospective zones are in the Triassic and Mississippian
- Purchase and shoot additional seismic in 1997, with drilling activity to commence in late 1997 to early 1998
- 23,040 acres

KAKWA

- Some land acquired in 1996, subsequent to year end a large farm-in was concluded
- Seismic will be shot in early 1997
- One re-entry well and one well to be drilled by mid-1997
- Reserve potential for gas in the Cardium and Fahler formations, and Bullhead Group
- 1,920 acres
- 25,920 acres tied-up under farmin arrangements

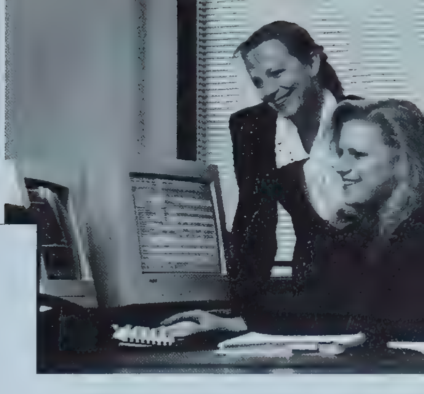
NARRAWAY

- Prospective for Cardium, Dunvegan, Cadotte and Belloy gas
- 1997 plans include seismic acquisition and identifying drilling targets
- 13,440 acres

Petromet's average product prices were stronger in 1996 than in previous years due to harsh winter conditions in 1995/1996 across most of North America leading to strong summer injection demand to replenish inventories. These conditions were followed by an early 1996/1997 winter season. The full impact across North America has not been shared equally by the Western Canadian Basin as excess gas deliverability and insufficient pipeline capacity have continued to hamper a fully integrated North American marketplace and put downward pressure on prices. These capacity restraints will continue to exist until significant new pipeline expansions come onstream. These pipeline expansions are not expected to occur until late 1998.

NATURAL GAS Petromet's average natural gas price increased 16 percent to $1.63 per thousand cubic feet in 1996 compared to $1.41 in 1995. The Company maintains a diverse market portfolio of gas sales by term, market type and pricing instruments. The majority of Petromet's portfolio was sold directly to a variety of markets including industrial end-users, marketing intermediaries and local distribution companies, with less than one percent sold to supply aggregators. Direct sales allow Petromet to maintain flexibility and adaptability in response to the ever changing dynamics of the North American gas industry. In addition, the Company's low operating costs put Petromet in the enviable position of being able to avoid unattractive long-term price commitments driven by temporary depressed market conditions.

In 1996, 32 percent of Petromet's gas was sold on terms under one year. One-year term sales accounted for 28 percent and sales under long-term contracts (greater than one year) totalled 40 percent of the Company's



portfolio. As part of Petromet's market diversification, the Company entered into a 12-year agreement with a marketing intermediary which commenced in November 1996. Through this agreement, Petromet achieves direct exposure to the Northeastern U.S. marketplace. In addition, the Company is participating in the Northern Border pipeline expansion through a marketing intermediary which is scheduled for initial deliveries to the Midwest U.S. in November 1998. Both long-term markets have the benefit of achieving direct geographical market diversification while maintaining pricing term and instrument flexibility.

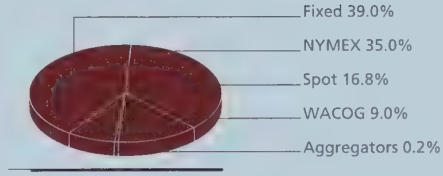
In terms of its market portfolio, Petromet is focusing on shorter-term fixed pricing commitments in order to take advantage of favourable market conditions over the next few years.

Pricing instruments responsive to market benchmarks increased to 61 percent in 1996 from 50 percent in 1995. Markets with pricing based on NYMEX futures contracts have grown to 35 percent in 1996 from 19 percent in 1995. Eastern Canadian WACOG pricing accounted for approximately nine percent of the Company's portfolio in 1996, while spot sales represented 17 percent. Spot sales will continue to be a part of the Company's overall portfolio mix in order to accommodate production increases, maintain exposure to local markets and provide additional volumes for new contracts at appropriate price levels.

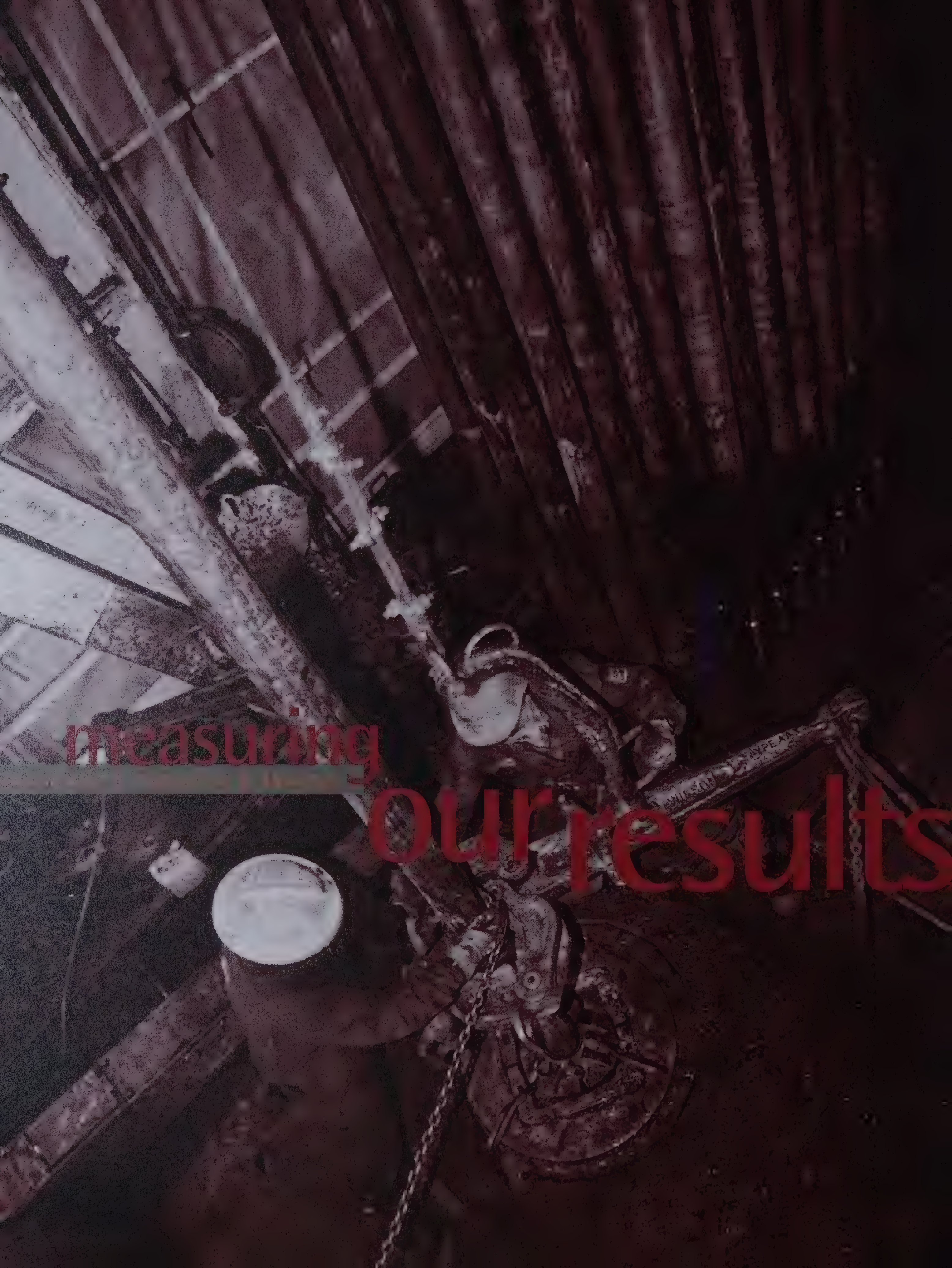
Export pipeline capacity restraints will continue to dampen natural gas prices. Other influencing factors in the Western Canadian Basin in 1997 include hydro electric competition, gas storage levels and weather conditions in California and the Pacific Northwest. Petromet believes these factors will contribute to increased natural gas demands. We expect our average price received will increase slightly over 1996.

CRUDE OIL AND NATURAL GAS LIQUIDS Petromet received an average price of $24.25 per barrel for its crude oil and natural gas liquids production in 1996 compared to $17.86 in 1995. Strong world wide demand for all products, especially propane, all contributed to this price increase. Petromet continues to market the majority of its natural gas liquids under a long-term contract which expires in September 1997 at which time the Company will actively pursue new markets for its production. As the natural gas liquids marketplace is showing signs of a transformation in its own rights (increased market opportunities for Alberta producers), Petromet will position itself to take advantage of the changing dynamics within Alberta.

1996 GAS SALES DISTRIBUTION
% OF VOLUME



Above: Lorene Holizki and Mary-Lou Zimmer



measuring our results

MANAGEMENT'S

DISCUSSION AND ANALYSIS

Management's discussion and analysis should be read in conjunction with the consolidated financial statements contained in this annual report. The following discussion contains certain assumptions about future events and actual results may vary significantly from these assumptions.

OPERATIONS Operating income increased 51 percent in 1996 to $20.5 million from $13.5 million in 1995 as follows:

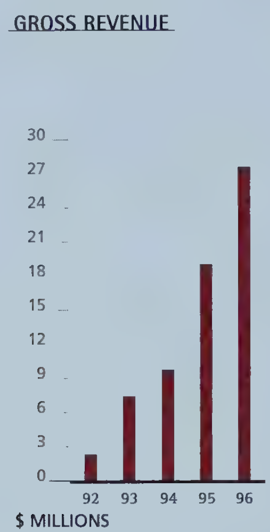
OPERATING INCOME ($ thousands)	1996	1995	1994
Petroleum and natural gas revenue	$ 27,911	$ 19,144	$ 9,665
Royalties	4,258	2,423	1,474
Operating costs	3,191	3,207	1,257
Operating income	$ 20,462	$ 13,514	$ 6,934
OPERATING INCOME PER BOE	**1996**	**1995**	**1994**
Sales price	$ 18.30	$ 14.98	$ 18.47
Royalties	2.79	1.90	2.82
Operating costs	2.09	2.51	2.40
Operating netback per BOE	$ 13.42	$ 10.57	$ 13.25

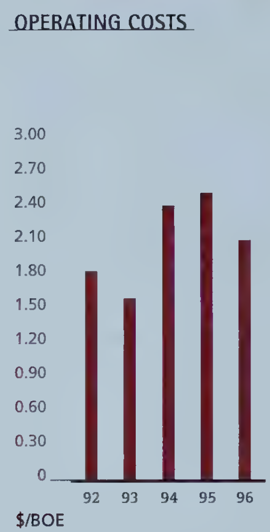
Petroleum and natural gas sales increased 46 percent to $27.9 million from $19.1 million in 1995. This increase resulted from gains in both production volumes and product pricing. Overall production increased 19 percent contributing an additional $4.4 million to gross revenue while product pricing increased 20 percent resulting in additional gross revenue of $3.8 million.

Natural gas and associated liquids continue to account for the majority of Petromet's production as illustrated in the components of gross revenue:

	1996		1995		1994	
	Gross Revenue	%	Gross Revenue	%	Gross Revenue	%
Natural gas sales	$ 19,737	71	13,919	73	8,343	86
NGL sales	7,392	26	4,758	25	763	8
Oil sales	230	1	462	2	442	5
Other	552	2	5	–	117	1
Petroleum and natural gas revenue	$ 27,911	100	19,144	100	9,665	100

Above: Christina Ingram, Kathy Prichard, Tara Bamsey and Sharon Supple





Natural gas sales averaged 33.1 million cubic feet per day, up 23 percent from 27 million cubic feet in 1995. Production increases were attained mainly from the Pass Creek and Bigstone West areas, resulting in additional sales of $3.2 million. A colder heating season in 1996 caused an increase in natural gas prices, which is reflected in the Company's average 1996 price of $1.63 per thousand cubic feet versus $1.41 in the prior year. This 16 percent rise in gas price increased natural gas revenue in 1996 by $2.6 million. Production of natural gas liquids increased seven percent to 859 barrels per day from 801 in 1995. Production increases in liquids did not correspond to those of natural gas due to the composition of the new gas added from the Pass Creek area. The new liquids production added $0.6 million to NGL revenue. Increased demand for liquids during the year was reflected in higher prices. The average liquids price received by the Company increased 36 percent resulting in an additional $2.0 million of revenue. Other income arises mainly from the capital component charged to third parties processing through Company-owned facilities.

Royalty payments, net of ARTC, increased as a percentage of petroleum and natural gas sales to 15.3 percent in 1996 from 12.7 percent in 1995. This increase resulted from higher product prices and therefore higher crown royalty rates, as well as the effect of reaching the maximum entitlement under the ARTC program. The net average royalty rate paid in 1997 is expected to increase slightly in accordance with prices received and the continuing impact of new production on which additional ARTC will not be applicable.

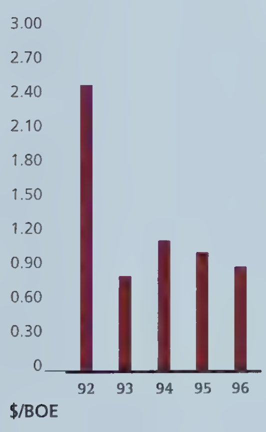
Operating costs on a barrel of oil equivalent basis declined from $2.51 in 1995 to $2.09 in the current year. Operating costs declined in the current year due to increased throughput at the Bigstone West facility. Operating costs are presented net of the operating portion of any recoveries realized from third-party processing in Company owned facilities. Operating costs in 1997 are expected to remain relatively unchanged. Petromet continues to operate the majority of its production and will continue to pursue similar conditions whenever possible to maintain control over operating costs.

CASH FLOW General and administrative expenses were $1.4 million in 1996 (net of overhead recovered by the Company as operator) reflecting an increase of $52,732 over 1995. Minimal staff increases occurred during 1996 despite the 19 percent increase in Company production. Overhead recovered by the Company from operating, drilling and construction activities increased slightly in 1996. Net general and administrative expenses were $0.90 per barrel of oil equivalent in 1996 versus $1.03 in 1995. General and administrative expenses on a barrel of oil equivalent basis are expected to remain consistent in 1997.

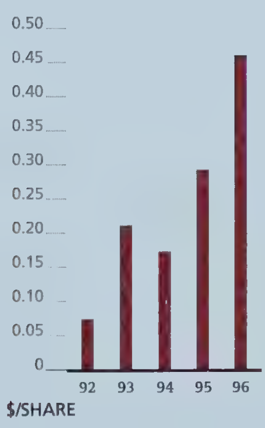
Above: Laurie Smith and Sam Degenstien

GENERAL AND ADMINISTRATIVE ($ thousands)	1996	1995	1994
Gross expenses	$ 2,406	$ 2,298	$ 1,597
Operator recoveries	1,033	977	1,004
Net expenses	$ 1,373	$ 1,321	$ 593
Average cost per BOE	$ 0.90	$ 1.03	$ 1.13
Employees at December 31			
Head office	19	19	16
Field operations	10	7	6
Total	29	26	22

GENERAL AND ADMINISTRATIVE COSTS



CASH FLOW/SHARE



Interest expense in 1996 is comprised of $1.6 million paid on the convertible debentures and $1.3 million arising from utilization of banking facilities. The convertible debentures were restated retroactively to conform to the new recommendations of the Canadian Institute of Chartered Accountants relating to the presentation and disclosure of financial instruments. The debentures have been restated into a financial liability component representing the principal and interest obligation and an equity interest component representing the holders' option to convert into common shares. This restatement resulted in an equity interest component of $2.8 million which is reflected in the financial statements as paid in capital. The equity component is amortized to interest expense over the life of the convertible debentures, resulting in a non-cash interest expense in the current year of $280,000. The convertible debentures are discussed further in the notes to the consolidated financial statements. Overall, interest expense increased slightly in 1996 due to higher average outstanding balances, offset by lower interest rates on the banking facility.

Petromet's large corporations tax was $261,000 in 1996 versus $226,000 in 1995 as a result of an increase in the company's capitalization.

Cash flow from operations increased 74 percent over the 1995 year to $15.9 million from $9.1 million. Cash flow on a BOE basis increased from $7.14 to $10.44 in 1996.

CASH FLOW		1996		1995		1994
Cash flow ($ thousands)	$	15,930	$	9,126	$	4,621
Per share ($)	$	0.46	$	0.29	$	0.17
Per BOE ($)	$	10.44	$	7.14	$	8.83

CASH FLOW SENSITIVITIES		Cash Flow $ Thousands		$/Per Share
Natural gas				
Change of $0.10/mcf in average price	$	998	$	0.03
Change of 10 mmcf/d production		4,228		0.12
Oil and NGL				
Change of $1.00/bbl in average price		307		0.01
Change of 100 bbls/d production		453		0.02

NET INCOME Depletion and depreciation on a barrel of oil equivalent basis increased to $6.34 in 1996 from $6.00 in the prior year. The provision for future abandonment and site restoration, included in the depletion and depreciation, remained constant at $0.31 per barrel of oil equivalent in 1996 ($0.32 in 1995). Depletion on a per unit basis increased due to a higher depletable base resulting from current capital expenditures and increased production. Depreciation on gas plant facilities is calculated on a straight line basis over the life of the facilities. The provision for future abandonment and site restoration is determined by management in consultation with the Company's engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at $6.6 million at December 31, 1996 (1995 – $6.0 million). Current expenditures for abandonment and site restoration of producing properties were minimal.

DEPLETION AND DEPRECIATION PER BOE		1996		1995		1994
Depletion	$	5.32	$	5.01	$	4.99
Depreciation		0.71		0.67		0.67
Site restoration provision		0.31		0.32		0.31
	$	6.34	$	6.00	$	5.97
Depletion rate		7.28%		6.77%		3.43%

The gain on sale of investment in the current and prior year resulted from the sale of securities received as part of a debt settlement which occurred in 1992. The original debt was written off and as a result the securities received were not reflected on the balance sheet and the entire proceeds received on the sale have been recorded as a gain. In 1994, the Company sold a portion of an investment for proceeds of $2.4 million which were reinvested in a treasury issue of the same company. The gain realized on the sale was deferred until the final disposition of the investment in 1996.

The provision for deferred income taxes in 1996 is $3,774,000 representing an effective rate of 37.8 percent versus an effective rate of 17.5 percent in 1995. The net effective tax rate for both years includes the tax effect of the gain on sale of investments in the year. The effective tax rate can vary substantially from year to year depending on the relative contribution of income sources, incentive allowances and non-deductible expenses. The Company had approximately $105 million of tax pools remaining at December 31, 1996 and is not expected to be taxable on a current basis in 1997.

Net income for the year ended December 31, 1996 was $5.9 million compared to $1.7 million in the prior year. Earnings per share for the year increased to $0.17 per share from $0.05 per share. The weighted average number of common shares outstanding increased nine percent over the comparable period.

LIQUIDITY AND CAPITAL RESOURCES Capital expenditures in 1996 of $23.2 million were financed through the current year's cash flow of $15.9 million, proceeds on the sale of investments of $3.7 million, and a portion of the flow-through share issue completed in the fourth quarter. The Company issued 3,100,000 flow-through common shares in November 1996 for gross proceeds of $10.2 million. This issue brought the total outstanding common shares to 37,032,139 at year end.

At year end, the Company had working capital of $1.0 million and had drawn $15.5 million on the bank facilities. The current bank facilities are available up to $30 million subject to the annual review of current activities and reserves. The 1997 capital budget is currently $30 million, although this amount is subject to revision as projects progress and additional opportunities arise. The budgeted amount will be mainly financed through cash flow with any additional requirements funded with the bank facilities.

BUSINESS RISKS Exploration, development and production of oil and natural gas involves many risks which even a combination of experience, knowledge and careful evaluation may not be sufficient to overcome. These risks are mitigated by employing highly skilled staff, focusing exploration efforts in areas in which Petromet has existing knowledge and expertise or access to such expertise, using up-to-date technology methods, and controlling costs to maximize returns. In addition, the Company's strategy of maintaining controlling interests and owning/operating facilities ensures that it will continue to be a low cost producer. The Company has a comprehensive insurance program designed to mitigate risks and protect against significant losses; however, it is not fully insured against all of these risks, nor are all such risks insurable. Insurance for liability, property and business interruption is considered adequate and is consistent with common industry practice.

Financial risks include exposure to fluctuations in interest rates, currency exchange rates and commodity prices. To reduce exposure to currency rate fluctuation associated with natural gas sales priced in U.S. dollars, the Company has fixed the Canadian/U.S. rate on a portion of 1997 production. At year end the cost to the Company to settle these contracts is estimated at $218,000. Although not currently utilized, the Company may institute hedging techniques for interest rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount established by the Board of Directors. To mitigate commodity price risk, the Company maintains direct marketing control over its production and maintains a diversified portfolio to reduce exposure to short-term fluctuations. Purchasers of the Company's production are subject to internal credit review and the Company is not aware of any of its sales being subject to undue credit risk.

The oil and gas industry, while subject to stringent environmental regulatory control, is undergoing significant change with increased responsibility of self-regulation and compliance. In view of this situation, Petromet has taken a proactive approach in improving the environmental performance of the Company by initiating the development of an Environmental Management System. This Environmental Management System essentially sets out the corporate environmental philosophy, objectives, risk assessment, organizational structure, policies, procedures, and auditing functions necessary in providing an effective comprehensive method of controlling all environmentally related issues. Such a system focuses on prevention and mitigation, rather than reaction and response techniques after environmental incidents have occurred. The system will also incorporate existing safety policies and emergency response plans, as a complete package, to ensure the protection of the environment and the safety of the general public and all personnel. Petromet retains the services of an environmental consulting firm to provide advice, current regulatory information, to prepare environmental assessments for facilities, pipelines and sites prior to commencement of a project and to audit the Environmental Management System.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared utilizing management's best estimates and judgements. In the opinion of management, these consolidated financial statements have been prepared within reasonable limits of materiality and are in accordance with Canadian generally accepted accounting principles.

Petromet maintains systems of internal controls to provide reasonable assurance that assets are safeguarded and to facilitate the preparation of relevant and reliable financial information on a timely basis.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee, consisting of a majority of non-management directors, has reviewed the consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

L.J. Smith
President & Chief Executive Officer

S.A. Supple
Chief Financial Officer

AUDITORS' REPORT

TO THE SHAREHOLDERS OF PETROMET RESOURCES LIMITED

We have audited the consolidated balance sheets of Petromet Resources Limited as at December 31, 1996 and 1995 and the consolidated statements of income, retained earnings and changes in financial position for the years ended December 31, 1996, 1995 and 1994. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1996 and 1995 and the results of its operations and the changes in its financial position for the years ended December 31, 1996, 1995 and 1994 in accordance with generally accepted accounting principles.

KPMG.

Chartered Accountants
Calgary, Canada
March 7, 1997

CONSOLIDATED

BALANCE SHEET

December 31 ($ thousands)	1996	1995
Assets		
Current		
Cash and term deposits	$ 7	$ 572
Accounts receivable	5,584	5,858
Inventory	1,330	2,186
Investments	125	2,525
	7,046	11,141
Property, plant and equipment (Note 2)	124,673	110,713
	$ 131,719	$ 121,854
Liabilities		
Current		
Accounts payable and accrued liabilities	$ 6,105	$ 6,523
Long-term bank debt (Note 3)	15,524	22,880
Convertible debentures (Note 4)	22,970	22,690
Deferred gain (Note 5)	–	2,400
Future abandonment and site restoration costs	1,220	750
Deferred income taxes	3,488	5
Shareholders' Equity		
Share capital (Note 6)	68,428	58,559
Paid in capital (Note 4)	2,800	2,800
Retained earnings	11,184	5,247
	82,412	66,606
	$ 131,719	$ 121,854

On Behalf of the Board:

(Director)

(Director)

CONSOLIDATED STATEMENT

OF INCOME

Year ended December 31 ($ thousands, except per share data)	1996	1995	1994
Revenue			
Petroleum and natural gas	$ 27,911	$ 19,144	$ 9,665
Royalties	(4,258)	(2,423)	(1,474)
	23,653	16,721	8,191
Expenses			
Operating	3,191	3,207	1,257
General and administrative	1,373	1,321	593
Depletion and depreciation	9,677	7,668	3,123
Interest on long-term debt	3,178	3,121	1,525
Other interest	–	–	272
	17,419	15,317	6,770
Income before other item and taxes	6,234	1,404	1,421
Gain on sale of investments	3,738	961	–
Income before taxes	9,972	2,365	1,421
Taxes (Note 8)	4,035	641	534
Net income	$ 5,937	$ 1,724	$ 887
Earnings per share	$ 0.17	$ 0.05	$ 0.03
Weighted average number of common shares outstanding (Note 1(f))	34,347,166	31,611,591	26,506,240

CONSOLIDATED STATEMENT

OF RETAINED EARNINGS

	1996	1995	1994
Balance, beginning of year (restated Note 4)	$ 5,247	$ 3,523	$ 2,636
Net income	5,937	1,724	887
Balance, end of year	$ 11,184	$ 5,247	$ 3,523

CONSOLIDATED STATEMENT

OF CHANGES IN FINANCIAL POSITION

Year ended December 31 ($ thousands)	1996	1995	1994
Cash provided by (used in)			
Operating Activities			
Net income	$ 5,937	$ 1,724	$ 887
Items not affecting cash:			
Depletion and depreciation	9,677	7,668	3,123
Deferred income taxes	3,774	415	401
Amortization of debt discount	280	280	210
Gain on sale of investments	(3,738)	(961)	–
Cash flow from operations	15,930	9,126	4,621
Change in non-cash working capital	712	(6,667)	591
	16,642	2,459	5,212
Investing Activities			
Property, plant and equipment, net	(23,167)	(37,921)	(57,094)
Purchase of investments	(1,650)	–	(2,400)
Sale of investments	5,388	961	2,400
	(19,429)	(36,960)	(57,094)
Financing Activities			
Common shares, net of issuance costs	9,578	28,324	2,837
Long term bank debt	(7,356)	6,738	16,142
Convertible debentures	–	–	25,000
Convertible debenture issue costs	–	–	(1,000)
	2,222	35,062	42,979
(Decrease) Increase in cash and term deposits	(565)	561	(8,903)
Cash and term deposits, beginning of year	572	11	8,914
Cash and term deposits, end of year	$ 7	$ 572	$ 11

December 31, 1996 ($ thousands)

1. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Petromet Resources Limited have been prepared by management in accordance with generally accepted accounting principles in Canada. The principal accounting policies followed by the Company are summarized below:

(a) Principles of consolidation The consolidated financial statements include the accounts of the Company and its subsidiaries.

(b) Investments Investments are recorded at the lower of cost and market value.

(c) Inventory Inventory of equipment is stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(d) Property, plant and equipment

(i) Petroleum and natural gas properties

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost centre representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and overhead charges directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of significant unproved properties are excluded from amounts subject to depletion until such time as the properties are proved or become impaired. Gas plants and related facilities are depreciated using the straight line method based on the estimated useful life of the assets.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired costs of non-producing properties less estimated future administrative expenses, development costs, financing costs, income taxes and estimated future abandonment and site restoration costs.

The amounts recorded for depletion and depreciation of property, plant and equipment and the provision for future abandonment and site restoration costs are based on estimates. The cost ceiling is based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) Future abandonment and site restoration costs

Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and

depreciation expense and actual abandonment and site restoration expenditures are charged to the accrued liability account as incurred.

(iii) Joint activities

Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(e) Financial instruments The Company uses forward foreign exchange contracts to reduce its exposure to fluctuations in exchange rates on future domestic sales denominated in U.S. dollars. Gains and losses incurred on forward contracts are recognized with the production revenue to which they relate.

(f) Earnings per share Basic earnings per share has been calculated using the weighted average number of common shares outstanding during the year which includes shares reserved for issuance of special warrants. Fully diluted earnings per share is not materially different from basic earnings per share.

2. PROPERTY, PLANT AND EQUIPMENT

	1996	1995
Petroleum and natural gas properties, at cost	$ 151,068	$ 127,901
Accumulated depletion and depreciation	(26,395)	(17,188)
	$ 124,673	$ 110,713

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 1996 were approximately $9,350 (1995 – $8,000).

3. LONG-TERM BANK DEBT

The bank debt has been advanced under a revolving demand credit facility in the amount of $30,000. The debt bears interest at the bank's prime lending rate, U.S. libor rate plus 3/4% or bankers' acceptance rates plus stamping fees. The facility is secured by a $100,000 floating charge oil and gas debenture but the agreement includes various covenants which influence the amount of additional debt and future security required under certain circumstances. The credit facility is renewable annually, however, no principal repayments are required providing certain reporting and financial covenants continue to be satisfied.

4. CONVERTIBLE DEBENTURES

(a) The Company has retroactively adopted the new recommendations of the Canadian Institute of Chartered Accountants relating to the presentation and disclosure of financial instruments. In accordance with these recommendations, the convertible debentures have been restated into their component parts. The financial liability component representing the principal and interest obligation is presented in long-term debt and an equity instrument component representing the holders' option to convert into common shares is presented in shareholders' equity. The proceeds received on the issue of the convertible debentures have been allocated to their component parts on the basis of their relative fair values resulting in an equity component of $2,800.

The new recommendations have been applied retroactively in these financial statements. The impact on the consolidated financial statements is as follows:

		1995		1994
Net income	$	(280)	$	(210)
Earnings per share		(0.01)		(0.01)
Convertible debentures		(2,310)		(2,590)
Paid in capital		2,800		2,800
Retained earnings		(490)		(210)

(b) The 6.5% convertible subordinate debentures are due March 31, 2004. The debentures are convertible into common shares at $9.50 per share and are non redeemable until March 31, 1999, unless the closing price of the common shares for 30 consecutive trading days is $15.25 per share or more. After March 31, 1999, the debentures are redeemable in the event that the weighted average price at which the common shares are traded during a 30 consecutive trading day period is not less than 130% of the conversion price.

5. DEFERRED GAIN

During 1994 the Company sold 600,000 common shares of an investment and realized proceeds of $2,400. The proceeds were invested in a treasury issue of the same company resulting in a purchase of 600,000 common shares and 300,000 common share purchase warrants. The warrants were exercised in 1996. The gain on the sale was deferred until the disposition of the investment in 1996.

6. SHARE CAPITAL

(a) The authorized share capital consists of an unlimited number of common shares and an unlimited number of preference shares, issuable in series. No preferred shares have been issued.

(b) Issued	Shares		Amount
Balance, December 31, 1993	23,787,139	$	17,170
Issued on warrant conversion	2,000,000		10,500
Issued for cash:			
Upon stock option exercise	1,145,000		2,837
Less: share and convertible debenture issue costs, net of deferred tax of $443	–		(904)
Balance, December 31, 1994	26,932,139		29,603
Issued for cash	7,000,000		29,750
Less: issue costs, net of deferred tax of $632	–		(794)
Balance, December 31, 1995	33,932,139	$	58,559
Issued for cash pursuant to flow-through share agreements	3,100,000		10,230
Less: issue costs, net of deferred tax of $291	–		(361)
Balance, December 31, 1996	37,032,139	$	68,428

(c) Stock option plan Stock options to acquire common shares are granted to directors, officers and other key employees from time to time at exercise prices equal to the market value of the shares at the date of the grant. At December 31, 1996, options to purchase 3,235,000 common shares were outstanding. These options are exercisable at prices ranging from $0.31 to $8.875 and expire on various dates between 1997 and 2001.

(d) Flow-through shares During the year the Company entered into flow-through share agreements whereby proceeds of $10,230 were received and the Company committed to expend and renounce $10,230 in qualified expenditures. Directors and officers of the Company subscribed for 173,500 flow-through shares for consideration of $573. At year end approximately $3,300 of the expenditures had been incurred.

7. FINANCIAL INSTRUMENTS

(a) Financial contracts The Company entered into forward foreign exchange contracts in 1996 to sell U.S. dollars for Canadian dollars. At December 31, 1996 the Company had purchased contracts to sell $6,650 U.S. dollars during 1997 at an average exchange rate of 1.3218 Canadian. The contracts are matched with anticipated future sales of foreign currencies. At year end the cost to the Company to settle these contracts based on quoted forward foreign exchange rates was $218.

(b) Fair value of financial instruments other than financial contracts The carrying amounts of cash and term deposits, accounts receivable, accounts payable and accrued liabilities and bank debt approximate their fair value. The fair value of other financial instruments is based on quoted market prices as follows:

	1996		1995	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Investments	$ 125	$ 245	$ 2,525	$ 3,510
Convertible debentures	22,970	21,750	22,690	20,750

8. TAXES

(a) The income tax expense differs from the amounts which would be obtained by applying the expected Canadian income tax rate as follows:

	1996	1995	1994
Income tax rate	44.6%	44.6%	44.3%
Computed "expected" tax provision	$ 4,447	$ 1,055	$ 629
Crown royalties	2,040	1,060	596
Non-deductible depletion	282	160	110
Resource allowance	(2,000)	(1,220)	(736)
Alberta Royalty Tax Credit	(655)	(657)	(278)
Non-taxable gains	(458)	(105)	–
Amortization of debt discount	125	125	94
Other	(7)	(3)	(14)
Large corporation tax	261	226	133
Provision for taxes	$ 4,035	$ 641	$ 534

(b) As at December 31, 1996 resource properties with a net book value of $9,400 (1995 – $6,500) have no cost base for income tax purposes. These differences arise primarily as a result of the acquisition of assets with a nominal value for income tax purposes and the issuance of flow-through common shares.

(c) As at December 31, 1996 the Company has available for deduction against future taxable income, resource deductions and undepreciated capital costs of approximately $105,000.

9. DIFFERENCES IN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES BETWEEN CANADA AND THE UNITED STATES

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. These principles differ from United States GAAP as follows :

(a) Under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10%, (based on prices and costs at the balance sheet date) plus the lower of cost and fair value of unproven properties. The application of the full cost ceiling test under U.S. GAAP did not result in a write down of capitalized costs.

(b) Under U.S. GAAP deferred income tax assets or liabilities are computed on the difference between financial statement and income tax bases of assets and liabilities. Deferred income tax provisions are based on the change during the period in the related deferred income tax asset or liability accounts.

(c) Under U.S. GAAP the reduction of stated capital, at December 31, 1992, would not have reduced the deficit. Accordingly retained earnings as at December 31, 1996 would have been $800 (1995 – a deficit of $3,864).

(d) Under U.S. GAAP the investments are classified as available for sale securities and would be reported at fair value, with the unrealized gains and losses net of related income taxes reported as a separate component of shareholders' equity.

(e) Under U.S. GAAP the equity component of the convertible debentures would be classified as debt on the balance sheet in accordance with the legal form of the instrument. The amortization of the debt discount would not be reported as an expense in the income statement.

The impact of the differences between Canadian and U.S. GAAP on the consolidated statement of income are as follows:

	1996	1995	1994
Net income as reported	$ 5,937	$ 1,724	$ 887
Increase in depletion	(196)	(196)	(77)
Amortization of debt discount	280	280	210
Liability method of income taxes	(1,357)	623	168
Net income under U.S. GAAP	$ 4,664	$ 2,431	$ 1,188
Earnings per share under U.S. GAAP	$ 0.14	$ 0.08	$ 0.04

The impact of the differences between Canadian and U.S. GAAP on the consolidated balance sheet is as follows:

	Canadian GAAP	Increase (Decrease)	U.S. GAAP
December 31, 1996			
Investments	$ 125	$ 120	$ 245
Property, plant and equipment	124,673	1,573	126,246
Convertible debentures	22,970	2,030	25,000
Deferred income taxes	3,488	3,489	6,977
Share capital	68,428	9,278	77,706
Paid in capital	2,800	(2,800)	–
Unrealized gain on investments	–	80	80
Retained earnings	11,184	(10,384)	800
December 31, 1995			
Investments	$ 2,525	$ 984	$ 3,509
Property, plant and equipment	110,713	1,957	112,670
Convertible debentures	22,690	2,310	25,000
Deferred gain	2,400	(2,400)	–
Deferred income taxes	5	3,412	3,417
Share capital	58,559	9,278	67,837
Paid in capital	2,800	(2,800)	–
Unrealized gain on investments	–	2,252	2,252
Retained earnings (deficit)	5,247	(9,111)	(3,864)

FIVE YEAR

HISTORICAL SUMMARY

($ thousands except per share data)	1996	1995	1994	1993	1992*
Financial					
Revenue					
Petroleum and natural gas	$ 27,911	$ 19,144	$ 9,665	$ 7,417	$ 2,214
Royalties	4,258	2,423	1,474	1,354	364
	23,653	16,721	8,191	6,063	1,850
Expenses					
Operating	3,191	3,207	1,257	796	335
General and administrative	1,373	1,321	593	405	458
Depletion and depreciation	9,677	7,668	3,123	2,319	518
Interest	3,178	3,121	1,797	86	38
	17,419	15,317	6,770	3,606	1,349
Income before other items and taxes	6,234	1,404	1,421	2,457	501
Other items	3,738	961	–	849	(1,434)
Income before taxes	9,972	2,365	1,421	3,306	(933)
Taxes					
Current	261	226	133	41	–
Deferred	3,774	415	401	629	–
	4,035	641	534	670	–
Net income (loss)	$ 5,937	$ 1,724	$ 887	$ 2,636	$ (933)
Cash flow from operations	$ 15,930	$ 9,126	$ 4,621	$ 4,735	$ 1,019
Balance sheet information					
Capital expenditures, net	$ 23,167	$ 37,921	$ 57,094	$ 22,296	$ 3,753
Long-term debt	$ 38,494	$ 45,570	$ 38,552	$ –	$ –
Working capital (deficiency)	$ 941	$ 4,618	$ (2,611)	$ 4,483	$ 1,362
Shareholders' equity	$ 82,412	$ 66,606	$ 35,925	$ 29,958	$ 7,124
Common shares outstanding	37,032,139	33,932,139	26,932,139	23,787,139	17,731,551
Per share data					
Net income (loss)	$ 0.17	$ 0.05	$ 0.03	$ 0.11	$ (0.07)
Cash flow from operations	$ 0.46	$ 0.29	$ 0.17	$ 0.21	$ 0.07
Operating					
Daily production					
Natural gas (mmcf)	33.1	27.0	12.5	13.0	5.3
Oil and NGL (bbls)	859	801	188	71	18
Proven reserves					
Natural gas (bcf)	157.4	138.3	125.5	78.2	23.2
Oil and NGL (mbbls)	3,649	3,721	3,067	1,706	204
Proven plus probable reserves					
Natural gas (bcf)	207.2	171.1	159.5	119.6	39.0
Oil and NGL (mbbls)	4,559	4,656	3,897	2,811	995
Wells drilled					
Gross	29	24	40	23	6
Net	21	18	24	15	2

* Eleven months ended December 31

CORPORATE

INFORMATION

DIRECTORS

Edmond G. Eberts*†
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Calgary, Alberta

Charles J. Howard*
(President, Ausnoram Holdings Limited)
Toronto, Ontario

P. Grenville Schoch†
Chairman of the Board
Toronto, Ontario

Laurie J. Smith*
President & CEO
Calgary, Alberta

Sharon A. Supple
Chief Financial Officer
Calgary, Alberta

** Member, Audit Committee*
† Member, Management Compensation Committee

OFFICERS

P. Grenville Schoch
Chairman of the Board

Laurie J. Smith
President & CEO

David H. Erickson
Senior Vice-President

Sharon A. Supple
Chief Financial Officer

Blaine D. Holstein
Vice-President, Operations

Christopher W. Nixon
Secretary

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Osler, Hoskin & Harcourt
Calgary and Toronto

Burstall Ward
Calgary, Alberta

BANKER

Royal Bank of Canada
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

The R-M Trust Company
Calgary and Toronto

AUDITORS

KPMG
Calgary, Alberta

LISTED

The Toronto Stock Exchange
Symbol: PNT

National Association of Securities Dealers, Inc. (NASDAQ)
Symbol: PNTGF

ANNUAL INFORMATION FORM

Copies of the Company's Annual Information Form are available upon request.

Designed and Produced by Parallel Strategies Inc.

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